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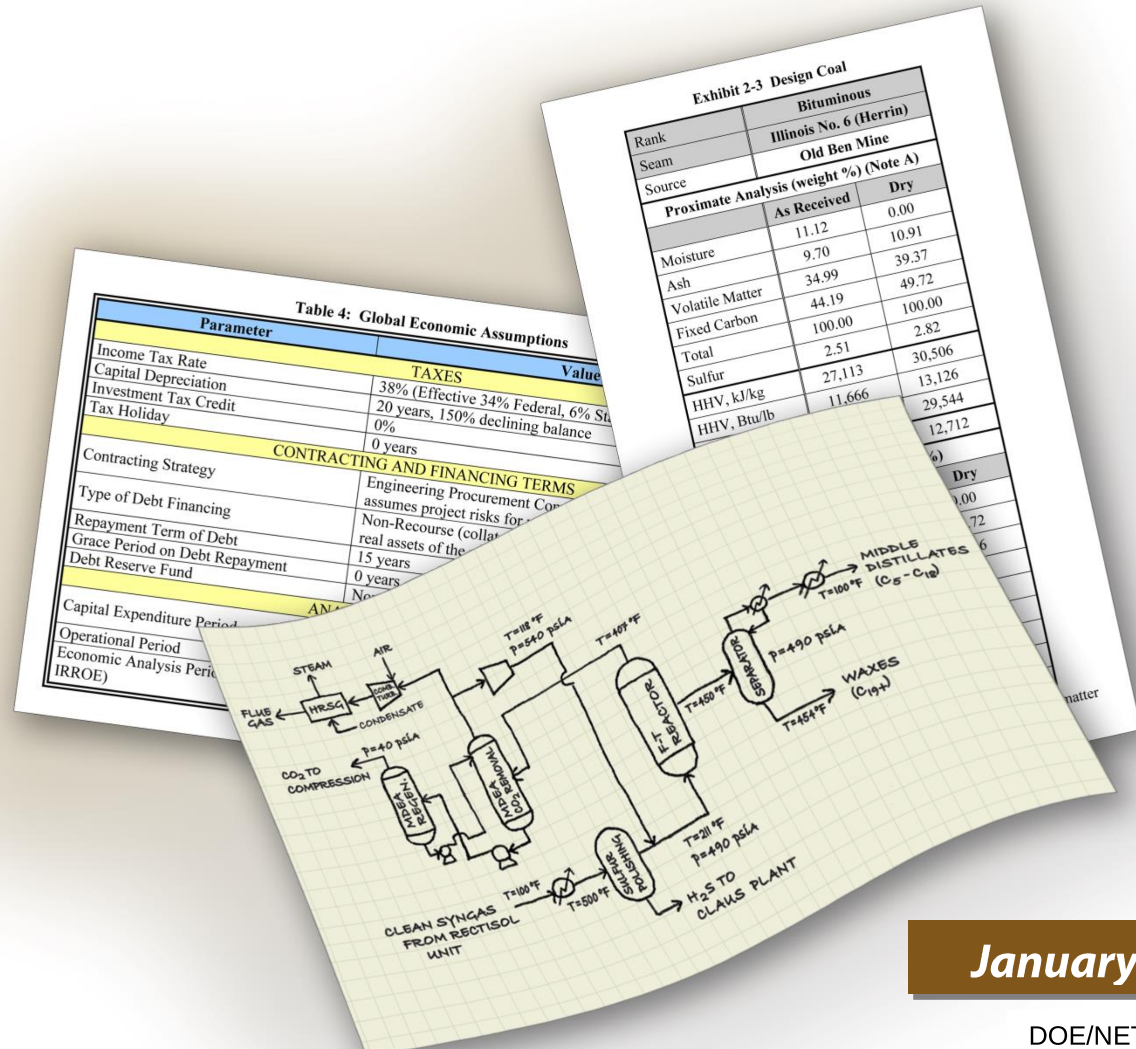
QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES

Detailed Coal Specifications



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Final Report

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List of Exhibits

Acronyms and Abbreviations

APFBC	Advanced pressurized fluidized bed combustion
ASTM	American Society for Testing and Materials
CO_2	Carbon dioxide
CTL	Coal-to-liquids
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FT	Fluid temperature
HAP	Hazardous air pollutants
HHV	Higher heating value
HRSG	Heat recovery steam generator
HT	Hemispherical temperature
HV	High volatile
ICR	Information collection request
IGCC	Integrated gasification combined cycle
IT	Initial deformation temperature
LHV	Lower heating value
ND	North Dakota
NETL	National Energy Technology Laboratory
NYPA	New York Power Authority
ppm	Parts per million
PRB	Powder River Basin
QGESS	Quality Guidelines for Energy System Studies
R&D	Research and development
SCPC	Supercritical pulverized coal
SNG	Synthetic natural gas
ST	Softening temperature
T&S	Transport and storage
TX	Texas
U.S.	United States

1 Objective

Specifications for selected feedstocks that are commonly found in the National Energy Technology Laboratory (NETL)-sponsored energy system studies are summarized in NETL's "Quality Guidelines for Energy System Studies" (QGESS). The purpose of this companion section is to document default QGESS specifications for coal compositions reflecting a spectrum of seven coal ranks:

- North Dakota (ND) lignite
- Texas (TX) lignite
- "super-compliance" subbituminous, ~0.2 percent sulfur (as-received weight percent)
- subbituminous, > 0.5 percent sulfur (as-received weight percent)
- high volatile bituminous
- medium volatile bituminous
- low volatile bituminous

2 Approach

The QGESS coal specification selection process was based on the following criteria:

1. Recommendations for QGESS were selected from the coal analyses most commonly used in the previous system studies to maximize the comparability of future system studies with those done in the past. A list was compiled of the coal types used in studies of coal-fueled energy conversion systems. Based on the frequency of coal types in this listing, one coal type was recommended as the QGESS default for each of the seven coal ranks.
2. Selected default coal specifications are, as much as possible, representative of the typical coal quality in the United States (U.S.) commercial market (i.e., as procured by the power plants in the U.S.). Some coal analyses in this current version of QGESS were obtained from the Argonne Premium Coal Sample Program that report as-mined coal properties. [1] The as-mined analyses are potentially different from as-shipped (or as-received) due to possible coal beneficiation at the mine prior to shipment (coal preparation at the mine is described in Section 3.5 of this report). Since the purpose of these coal analyses is to provide a consistent basis for energy system modeling, this distinction (as-mined versus as-shipped composition) is not a primary concern. Other coal composition data sources are documented in Section 7.
3. If there were compelling reasons to do so, a coal type other than that most frequently used in past studies could be recommended. For example, the most frequently used Pittsburgh No. 8 coal composition was similar to the currently used Illinois No. 6 composition. Therefore, an alternative Pittsburgh No. 8 composition was selected to provide a greater distinction between it and Illinois No. 6 coal.

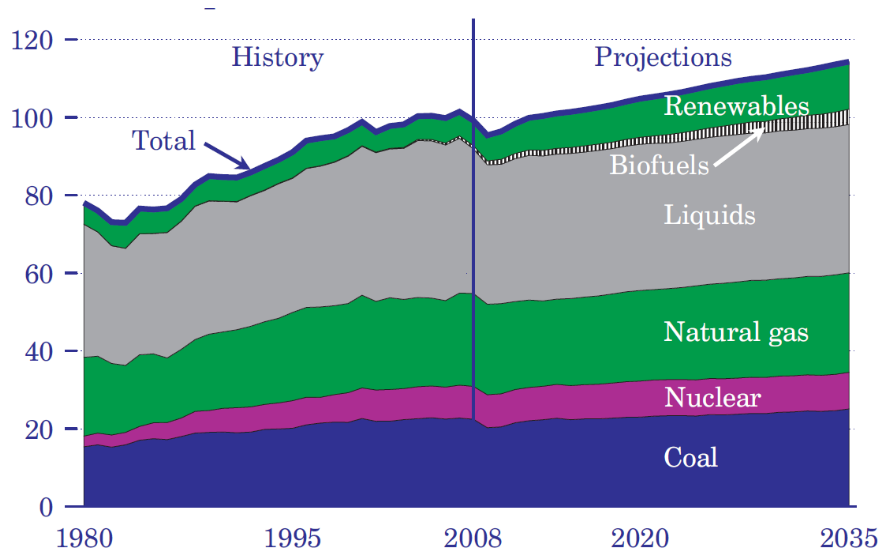
3 The U.S. Coal Industry

This section provides background information about the U.S. coal industry, including coal reserves, current and future coal demand, coal production, and coal cleaning methods at the mine. Information on characteristics of U.S. coal, transportation, and utilization at power plants can be found in the Department of Energy (DOE) NETL report, “Overview of U.S. Coal Supply and Infrastructure.” [2]

3.1 Coal Historical and Future Demand

Coal has been a major energy source for more than a century in the U.S. In the last five decades, coal production grew steadily from 434 million short tons in 1960, to 1,073 million short tons in 2009. According to the Energy Information Administration’s (EIA) Annual Energy Outlook 2010, although the long-term, 25-year outlook presents uncertainties -- resulting from the difficulty of accurately predicting future costs of producing and transporting coal, economic growth, world oil prices, and future greenhouse gas regulations -- coal demand is expected to be relatively steady (Exhibit 3-1). [3]

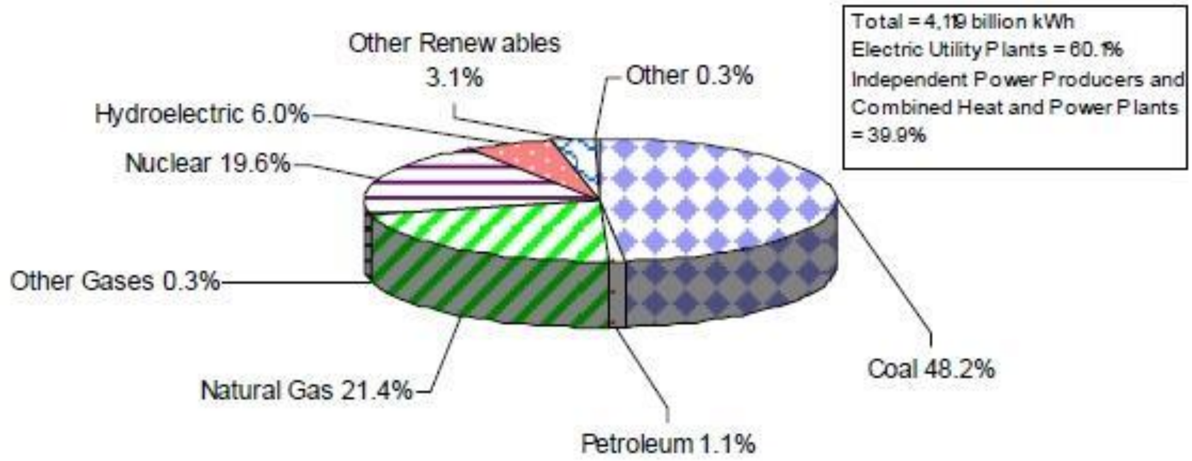
Exhibit 3-1 U.S. primary energy consumption, 1980-2035 (quadrillion Btu)



Source: U.S. EIA

In the last decade, natural gas utilization went through a solid growth period and has increased its share of the electricity market from 13.7 percent in 1997, to 21.4 percent in 2008. Renewable energy sources also have increased their share of total net power generation in recent years. Meanwhile, coal’s share of total net generation continued its downward trend, accounting for 48.2 percent in 2008 as compared to 52.8 percent in 1997. Nevertheless, coal continues to be the most important source of energy for the U.S. power industry (Exhibit 3-2). [4]

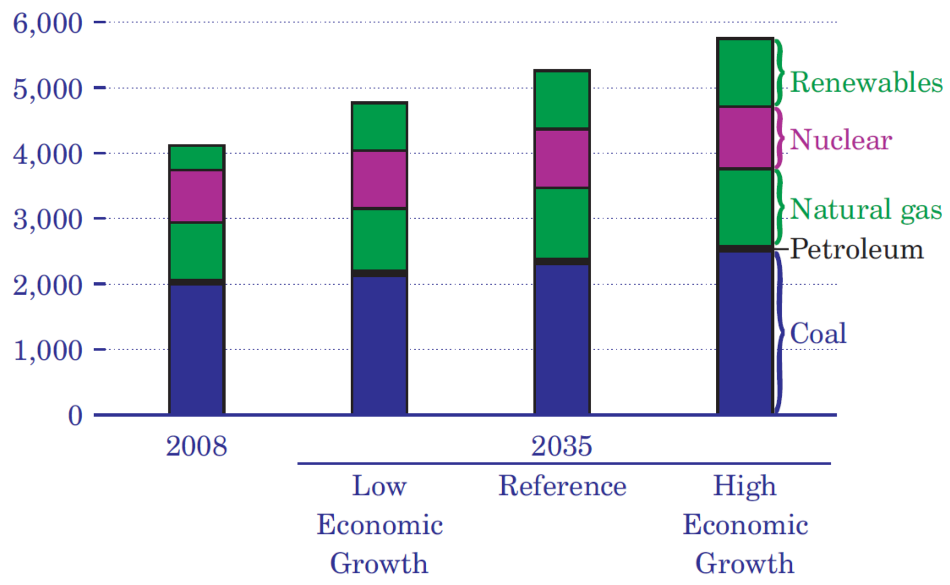
Exhibit 3-2 U.S. electric power industry net generation by fuel, 2008



Source: U.S. EIA

According to the EIA Annual Energy Outlook for 2010, in the next 25 years coal will retain its largest share position of total electricity generation, while most new capacity additions will be natural gas and renewable energy sources (Exhibit 3-3). [3]

Exhibit 3-3 Electricity generation by fuel, 2008 and 2035 (billion kilowatt-hours)



Source: U.S. EIA

3.2 Coal Deposits

In the U.S., coal is found in 37 states, with 6 states containing about 75 percent of recoverable reserves: Montana (28.7 percent), Wyoming (14.9 percent), Illinois (14.6 percent), West Virginia (6.7 percent), Kentucky (5.6 percent), and Pennsylvania (4.4 percent). [5]

The U.S. Geological Survey has divided the coal-bearing areas of the contiguous U.S. into six main provinces: Eastern, Interior, Gulf, Northern Great Plains, Rocky Mountain, and Pacific. The provinces are subdivided into coal regions, coal fields, and coal districts. The U.S. coal fields, by coal rank and geographical location, are presented in Exhibit 3-4. [6]

The Eastern province includes anthracite regions of Pennsylvania and Rhode Island, the Atlantic Coast region, and the Appalachian region. The Appalachian region is of most importance in the Eastern province. It is one of the great coal producing regions in the U.S., and contains the largest deposits of high-grade bituminous coal. The Appalachian region includes portions of Pennsylvania, West Virginia, Ohio, Maryland, Kentucky, Virginia, Tennessee, and Alabama.

The Interior province includes all bituminous coal in the Mississippi Valley area and the coal fields of Texas and Michigan. This province is subdivided into the Northern region consisting of the coal fields of Michigan; the Eastern region (a.k.a. Illinois basin) comprising fields of Illinois, Indiana, and western Kentucky; the Western region including the coal fields of Iowa, Missouri, Nebraska, Kansas, Arkansas, Oklahoma; and the Southwestern region of Texas. The bituminous coals of the Interior province are of lower rank and higher sulfur content as compared to the Eastern province. Much of the low sulfur, chlorine, and sodium content surface-mineable coal in the Illinois basin has been mined. The remaining coal with high chlorine content will have to be deep-mined.

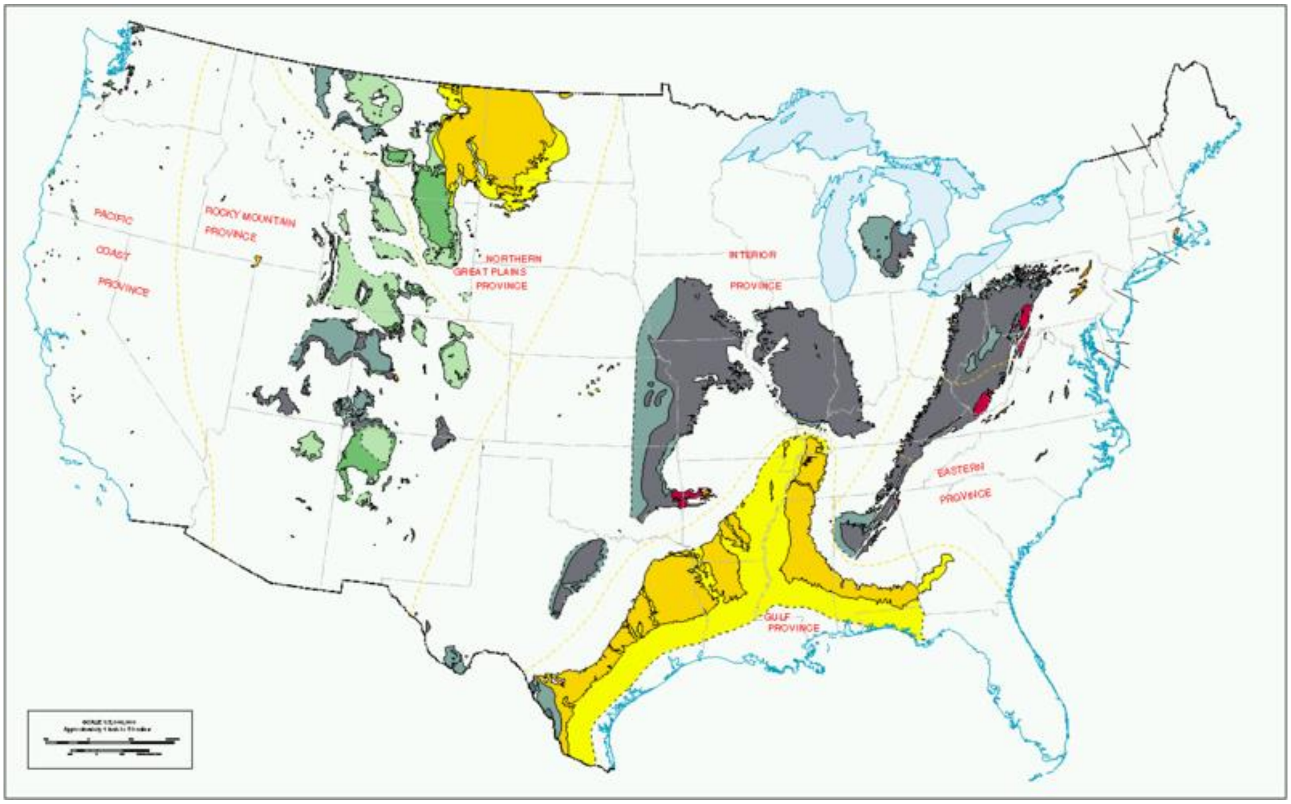
The Gulf province consists of the Mississippi region, including the lignite fields of Alabama, Mississippi, and Louisiana; and the Texas region that comprises the lignite fields of Arkansas and Texas. Coals found in the Gulf province are of the lowest quality in the U.S., with heating value as low as 4,000 Btu/lb, and moisture content as high as 55 percent.

The Northern Great Plains province includes all coal fields east of the Rocky Mountains, encompassing lignite fields of both Dakotas, bituminous and subbituminous fields of northern Wyoming, and northern and eastern Montana. This province includes immense deposits of low-sulfur, near-surface, and thick subbituminous coal seams of the Powder River Basin (PRB).

The Rocky Mountain province comprises the coal fields of mountainous areas of Montana, Wyoming, Utah, Colorado, and New Mexico. The deposits in this province cover a range of coal ranks.

The Pacific province is largely confined to the State of Washington, and ranges in rank from subbituminous through bituminous to anthracite.

Exhibit 3-4 U.S. coal fields

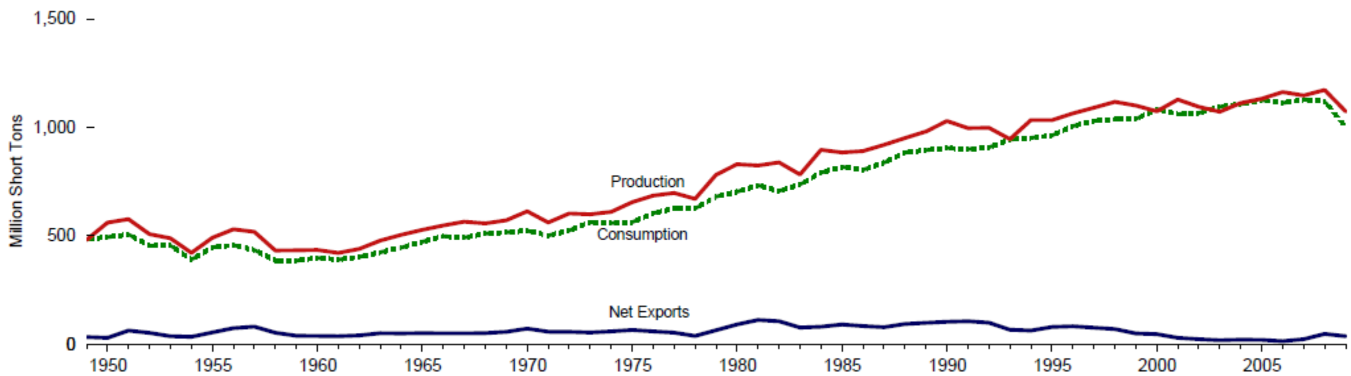


Source: U.S. Geological Survey

3.3 Coal Production

Unlike petroleum or natural gas, domestic production of coal nearly always exceeds U.S. consumption (Exhibit 3-5). [7] U.S. coal production has remained near 1,100 million tons annually since 1997.

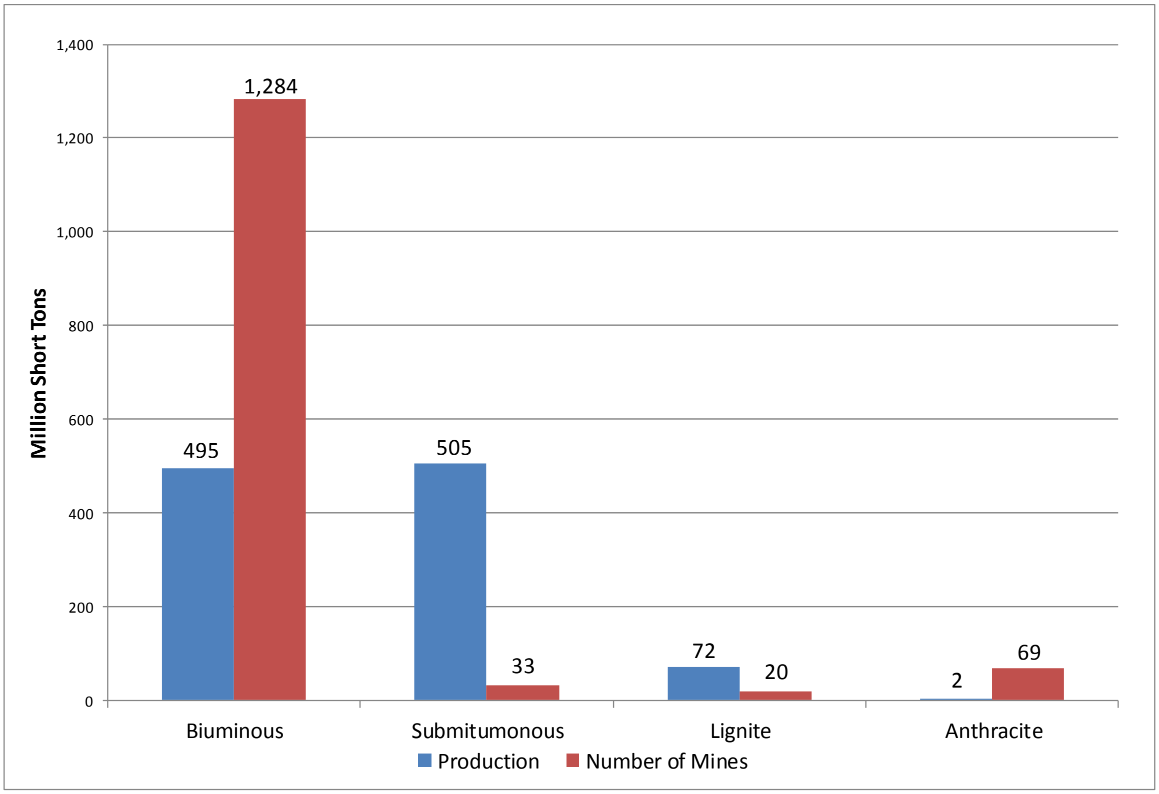
Exhibit 3-5 U.S. coal production versus demand, 1949-2009



Source: U.S. EIA

The distribution of the U.S. coal production by coal rank for 2009 is presented in Exhibit 3-6. [5]

Exhibit 3-6 Coal production by coal rank and number of mines

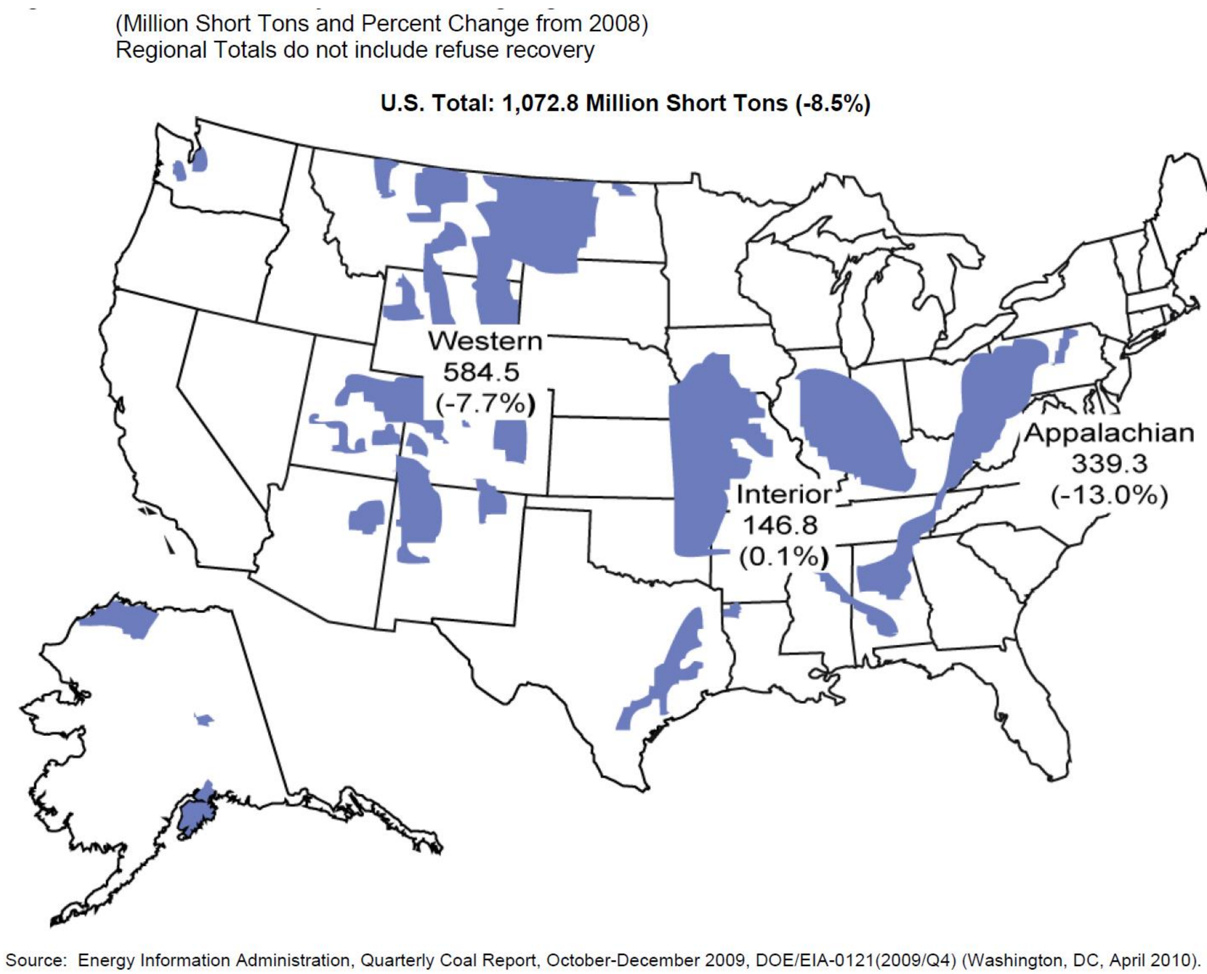


Source: Reproduced from U.S. EIA Data

The U.S. coal production decreased in 2009 by 8.5 percent to a total of 1,073 million tons from 2008 record level of 1,172 million tons due to the ongoing economic downturn (Exhibit 3-7). [8] The EIA uses "regions" as their highest level coal location descriptor as opposed to "provinces" used by the U.S. Geological Survey. The three coal regions in the EIA lexicon are Appalachian, Interior, and Western. The balance of this discussion uses the EIA region descriptors.

Both the Appalachian and Western regions had decreased coal production in 2009, while the Interior region remained almost steady, increasing by 0.1 percent. The decrease in coal production in the Appalachian region accounted for about half of the total decrease in U.S. coal production, while the Western region was responsible for the rest of the decrease.

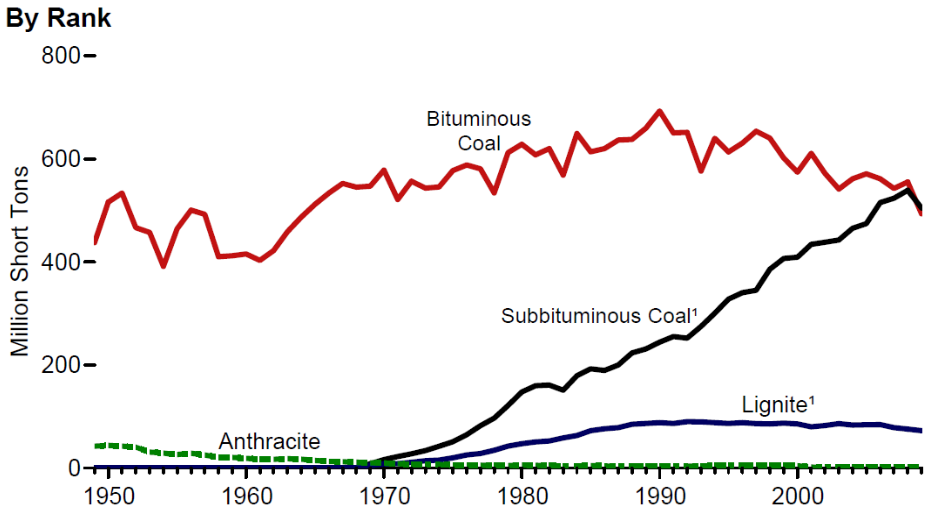
Exhibit 3-7 2009 coal production by coal-production region

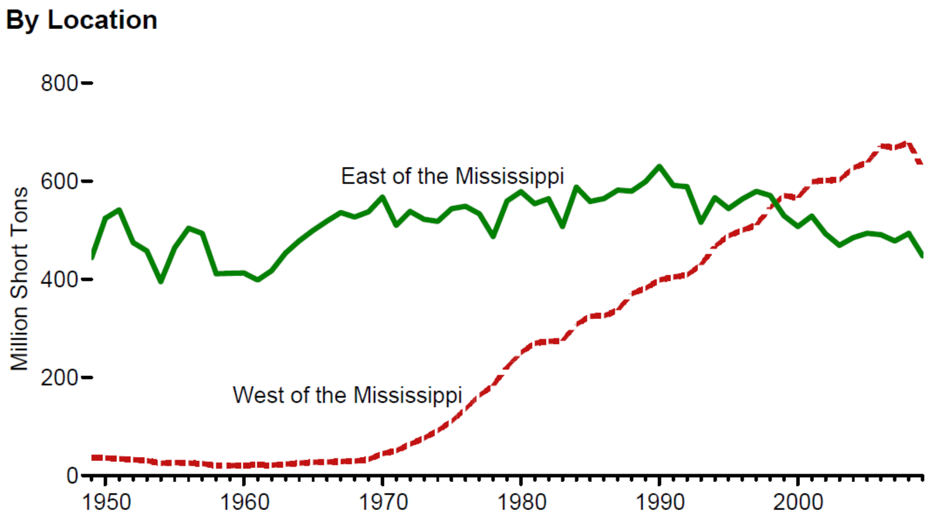


Source: U.S. EIA

Despite the one-year decrease between 2008 and 2009, Western coal production has been growing steadily since 1970, especially production of low sulfur subbituminous coals in the Powder River Basin (Exhibit 3-8). [7]

Exhibit 3-8 Historical coal production by coal rank and location





Source: U.S. EIA

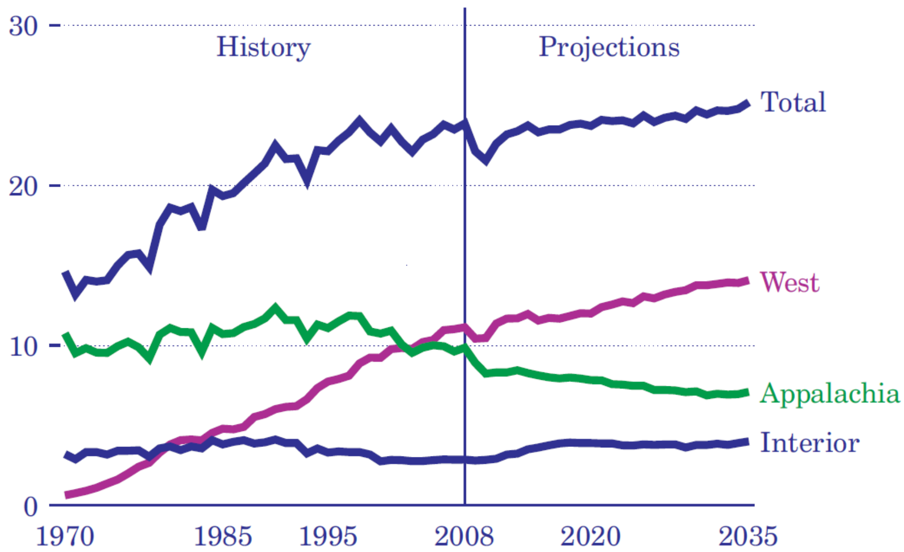
3.4 Coal Production Forecast

According to the EIA Annual Energy Outlook 2010 forecast, increase of coal use for electricity generation, along with projected startup of several coal-to-liquid (CTL) plants, should result in coal production growth averaging 0.2 percent per year from 2008 through 2035. This is significantly less than the 0.9 percent average growth rate for U.S. coal production during the 1980 to 2008 period. It is also expected that increasingly tight pollutant emissions caps will lead to more use of low-sulfur coal from the Western mines. Western coal production, which has grown steadily since 1970, is projected to continue to increase through 2035, but at a much slower rate than in the past (Exhibit 3-9). [3] Both new and existing electric power plants are projected to be major contributors to growth in demand for Western coal. Supplies of low-cost coal from the Western region are expected to satisfy most of the additional fuel needs at coal-fired power plants both west and east of the Mississippi River.

Coal production in the Interior region, which suffered a downward trend since the 1990s, is expected to rebound somewhat, primarily supplanting more expensive coal from Central Appalachia that is currently consumed at coal-fired power plants in the Southeast. Much of the additional output from the Interior region originates from mines tapping into the extensive reserves of mid- and high-sulfur bituminous coal in Illinois, Indiana, and western Kentucky. In addition, some of the anticipated growth in output from the Interior region results from increased lignite production in Texas and Louisiana.

Total production of Appalachian region coal is projected to decline from the current levels, as output shifts from extensively mined, higher cost supplies to lower cost supplies from the Interior region and the northern part of the Appalachian basin.

Exhibit 3-9 Current and projected coal production by region (quadrillion Btu)



Source: U.S. EIA

3.5 Coal Cleaning

As-mined coal contains a mixture of different size fractions, together with unwanted impurities such as rock and dirt. Coal preparation (also known as beneficiation) is the stage in coal production when the mined coal is processed into a range of clean, graded, and uniform coal products suitable for the commercial market. In a few cases, the mined coal is of such quality that it meets the user specification without beneficiation, and it is merely crushed and screened to deliver the specified product. Some power plants are fed from a single source of coal, but many utilities buy coals from different suppliers, and some blend these in order to give a consistent feed to the power plant. Blending also enables selective purchasing of different grades of coal. More expensive, higher-quality supplies can be mixed with lower-quality coals to produce an average blend suited to the plant needs, at optimum cost. Effective preparation of coal prior to combustion improves the homogeneity of coal supplied, reduces transport costs, improves the utilization efficiency, produces less ash for disposal at the power plant, and may reduce the emissions of oxides of sulfur.

Few coal seams are clean enough for coal to be shipped without cleaning. Consumers typically require coal of consistent quality. To prepare fuel conforming to customer specifications, practically all large, mechanized mines have preparation plants in which coal is sized and cleaned to the extent economically justified.

3.5.1 Nature of Coal Impurities

Coal is a heterogeneous mixture of organic and inorganic materials. Coal properties may differ not only from seam to seam, but also depending upon the coal location and elevation within the same seam. Coal impurities are typically classified as inherent and removable.

The inherent impurities in ash-forming mineral matter are organically combined with the coal. Approximately 2 percent of total coal ash-forming material is considered inherent mineral matter. [9] The bulk of the coal mineral matter is interstratified material which settles into the coal deposit as a result of water penetration during and after coal formation. Some of the mineral matter can be introduced into the coal during a mechanized mining process as a result of undesirable mixing with the overburden material. This is less likely for the larger and better strip mines that do not mine coal near the outcrop. The inherent impurities cannot be economically separated from the coal during coal preparation while removable impurities can be segregated and removed using cleaning methods.

Sulfur is present in the coal in three forms – pyritic sulfur (sulfur combined with iron in the form of pyrite), organic sulfur (sulfur combined with carbon in coal), and sulfate sulfur (sulfur in the form of calcium or iron sulfate). The latter usually does not exceed 0.1 percent of total sulfur. [9] The larger pieces of pyritic sulfur can be removed with mineral matter using coal cleaning methods. Fines of the pyritic sulfur and organic sulfur cannot be economically removed using modern cleaning methods.

3.5.2 Cleaning Methods

Most mechanical cleaning processes depend on differences in specific gravity of coal and impurities to facilitate separation. Typically, most common solid impurities are heavier than coal and can be removed by gravity concentration. The cleaning process may be wet or dry, with either water or air used as a medium. In general, wet processes are more efficient; however, determination of which process is more suitable for a specific coal depends upon the coal washability characteristics, i.e., properties of the various specific gravity fractions and the variations of these properties with coal sizing. The most frequently used wet methods are [9]:

Jigs - Pulsating currents of water pass through a bed of coal resting on a screen plate. The upward flow, called "pulsion stroke," fluidizes the coal, and the subsequent downward flow, called "suction stroke," settles the bed. While coal particles are in suspension they are separated into fractions and diverted into separate streams.

Dense-Media Method - Coal is immersed in a medium with specific gravity intermediate between that of coal and impurities. The impurities sink, and the coal floats.

Concentration tables - This method is primarily used for washing fine coal (50 mesh sizing)

Only a small percentage of the total coal is cleaned by pneumatic (dry) process in the U.S. It is typically applied to the coal less than ½ inch in size. The raw coal may be screened upstream from the cleaning plant with larger fractions directed to the wet process and smaller to the pneumatic process. In pneumatic processes, air is blown upward through the bed of coal resting on a moving table equipped with riffles. The air flow segregates coal and impurities by bringing particles with lower specific gravity (mostly coal) to the top of the bed. Low gravity particles then move across the table in direction perpendicular to the riffles. The heavy particles (mostly impurities) settle in the riffles and move along the riffles, discharging at the end opposite to the coal feed. Fines suspended in the air are recovered in cyclone separators and/or bag filters.

3.5.3 Special Treatment Methods

De-dusting - De-dusting is the process of coal fines removal using air separation. It is often utilized to remove fines ahead of wet cleaning. De-dusting is accomplished by passing an air stream through the coal with subsequent fine coal recovery in cyclone separators and bag filters. The fines may be added to clean coal (if low in ash) or disposed of with the impurities.

Dewatering - Larger size coal (above 3/8 inch) can be dewatered using gravity with special hoppers and bins with drainage, screen conveyors, or perforated bucket elevators.
When fine sizes need to be dried, or lower moisture content is required, mechanical dewatering or thermal drying is utilized. Mechanical dewatering devices include shaker or vibrating screens, centrifuges, and thickening equipment. Thermal dryers are of fluidized bed, rotary, cascade, reciprocating screen, and conveyer type. All thermal dryers require dust collection to recover fines, which may be centrifugal cyclones, bag filters, or water-spray systems. Thermal drying is predominantly used for obtaining low moisture content, fine-size coal.

Dust proofing - Dust proofing is accomplished by spraying oil and calcium chloride on streams of coal falling from chutes or loading booms. When coal is sprayed by oil, the film causes dust particles to adhere to the larger pieces or to agglomerate into larger lumps. About 13 percent of cleaned bituminous coal is sprayed by oil. [9] Sometimes coal is sprayed with oil and calcium chloride. Calcium chloride absorbs moisture from the air, providing a wet surface to which dust adheres.

Freeze proofing - Freeze proofing is used to prevent coal from freezing during transportation and storage. The most commonly used method is spray oil application, the same as dust proofing. Sometimes the railroad car hoppers are sprayed to ease coal unloading at the final destination. Less often freeze proofing is accomplished by thermal drying the fine coal, especially for high moisture content, low-rank coal.

4 Definition of Coal Specifications

4.1 ASTM Classification by Rank

Coal is a heterogeneous substance, with wide variability in composition. A system used for classifying coals was established by the American Society for Testing and Materials (ASTM), Exhibit 4-1. [9] The ASTM D388 classification system uses volatile matter and fixed carbon content in the proximate analysis along with the heating value of the coal to establish the coal rank. This ranking system provides basic information that assists in making judgments about the combustion properties and the commercial uses of the various types of coal.

4.2 Proximate Analysis

The proximate analysis (percent by weight) gives information on coal behavior when it is heated, e.g., how much coal goes off as gas, tar, and vapor, and how much remains as fixed carbon. The proximate analysis is described by ASTM Standard D3172. This determines volatile matter, fixed carbon, and ash. The quantity of volatile matter indicates ease of ignition of a coal and whether supplemental flame stabilization is needed.

4.3 Ultimate Analysis

The ultimate analysis (percent by weight) gives the coal composition by constituent elements. The ultimate analysis is described by ASTM Standard D3176. This establishes the quantities of carbon, hydrogen, nitrogen, and sulfur content in the coal, as well as the calculated oxygen content. The ultimate analysis is utilized for combustion calculations.

4.4 Higher and Lower Heating Value

The heat of combustion is usually determined by direct calorimeter measurements of the heat evolved. Heating value is either reported as 'higher heating value' (HHV), or as 'lower heating value' (LHV). The heating value of a fuel is a measure of the sensible energy released during combustion when both the fuel and combustion air are brought to standard conditions, the combustion reactions occur, and the products of combustion are brought back to standard conditions.

Heating value can be defined in one of two ways depending on the convention chosen for reporting how hydrogen energy in the fuel is released. The water vapor produced holds the heat of vaporization of the water. The HHV, also called gross heating value, of a fuel includes the heat released if all of the water vapor in the combustion products were condensed, releasing the heat of vaporization of the water in the combustion products. This is typically the situation that exists when a bomb calorimeter is used to measure the heat of combustion. The procedures for measuring HHV are described in ASTM Standard D5865. In the U.S., HHV is generally used in the coal power industry.

The LHV is the second definition frequently used to measure energy released during combustion. The LHV of a fuel is the heat released if all of the water vapor in the combustion products remained as a vapor, retaining the heat of vaporization of the water in the combustion products. In the U.S., LHV is generally used in the natural-gas and oil-fueled gas turbine industry, while in Europe LHV is typically utilized for all power industry applications.

Exhibit 4-1 ASTM D388 classification of coals by rank

Group[a]	Fixed Carbon Limits, % (Dry Mineral-Matter-Free Basis)		Volatile Matter Limits, % (Dry, Mineral-Matter-Free Basis)		Calorific Value Limits, Btu/lb (Moist,[b] Mineral-Matter-Free Basis)		Agglomerating Character
	Equal or Greater Than	Less Than	Greater Than	Equal or Less Than	Equal or Greater Than	Less Than	
Class I – Anthracitic							
1. Meta-anthracite	98	--	--	2	--	--	Non-agglomerating
2. Anthracite	92	98	2	8	--	--	Non-agglomerating
3. Semianthracite[c]	86	92	8	14	--	--	Non-agglomerating
Class II - Bituminous							
1. Low volatile bituminous coal	78	86	14	22	--	--	Commonly agglomerating
2. Medium volatile bituminous coal	69	78	22	31	--	--	Commonly agglomerating
3. High volatile A bituminous coal	--	69	31	--	14,000[d]	--	Commonly agglomerating
4. High volatile B bituminous coal	--	--	--	--	13,000[d]	14,000	Commonly agglomerating
5. High volatile C bituminous coal	--	--	--	--	11,500	13,000	Commonly agglomerating
	--	--	--	--	10,500[e]	11,500	Agglomerating
Class III - Subbituminous							
1. Subbituminous A coal	--	--	--	--	10,500	11,500	Non-agglomerating
2. Subbituminous B coal	--	--	--	--	9,500	10,500	Non-agglomerating
3. Subbituminous C coal	--	--	--	--	8,300	9,500	Non-agglomerating
Class IV - Lignitic							
1. Lignite A	--	--	--	--	6,300	8,300	Non-agglomerating
2. Lignite B	--	--	--	--	--	6,300	Non-agglomerating

Notes:

- *a* *This classification does not include a few coals, principally non-banded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high volatile bituminous and subbituminous ranks. All of these coals either contain less than 48 percent dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free Btu/lb.*
- *b* *Moist refers to coal containing its natural inherent moisture, but not including visible water on the surface of the coal.*
- *c* *If agglomerating, classify in low volatile group of the bituminous class.*
- *d* *Coals having 69 percent or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.*
- *e* *It is recognized that there may be non-agglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high volatile C bituminous group.*

4.5 Grindability

Grindability is an empirical measurement of the relative ease with which a coal can be reduced in size, and is described by ASTM Standard D409.

4.6 Ash Properties

A successful boiler design requires proper sizing and arrangement of the furnace and tube surfaces. A first priority in any design is to minimize slagging and ash deposition problems. The slagging and the fouling potential of the coal directly affect furnace design, having a significant influence on tubing spacing. Ash analyses of the expected fuel source are performed before undertaking any boiler design, using ash prepared according to ASTM D3174.

- The slagging potential of ash is the tendency to form fused deposits on tube surfaces exposed to high temperature radiant heat.
- The fouling potential is the tendency of ash to bond to lower temperature convection surfaces.

4.7 Ash Fusion Characteristics

Many comparisons of chemical makeup have been developed to analyze the behavior of ash in boilers. Empirical testing of ash-fusion temperature is still the most basic way of predicting slagging and fouling-fusion temperature. This testing is prescribed in ASTM D1857. The test consists of observing the gradual thermal deformation (melting) of a pyramid-shaped ash sample and recording the initial deformation temperature (IT), softening temperature (ST), hemispherical temperature (HT), and fluid temperature (FT). The stages at which these temperatures are recorded are generally measured under reducing and oxidizing conditions.

4.8 Trace Elements

All coals contain trace elements, albeit in very small quantities, that are measured in parts per million. Typically, most trace elements in coal occur in abundances not greatly different from those in rock making up the crust of the earth, with the exception of boron, chlorine, and selenium. The 1990 Amendments to the Clean Air Act listed a number of minor and trace elements that commonly occur in coal as “hazardous air pollutants” (HAP).

Mercury is the element of greatest immediate concern because it is emitted from the plant stack, and limiting legislation is due to be finalized in November, 2011. Deposits containing high enough concentrations of arsenic and selenium to be of concern have been observed starting in low temperature gas cooling all the way through the boiler or heat recovery steam generator (HRSG). Air emissions of lead have been regulated by some states.

4.9 Coal Moisture

All coals contain moisture. Total moisture of a coal is comprised of surface moisture and inherent moisture. Inherent moisture is a quality of the coal seam in its natural state of deposition and includes only that water considered to be part of the deposit, and not that moisture which exists as a surface addition. Surface moisture is the water from external sources, such as weather or coal washing processes. The standard test method for total moisture in coal is defined in ASTM D3302.

The moisture content of coals varies widely by rank. In the high-rank, low volatile bituminous coals it is frequently under 5 percent. High volatile bituminous coals may have as much as 12 percent moisture and lignite, and as high as 45 percent as mined. [10] Coal as mined, shipped, and received may also contain varying amounts of water due to gain or loss in coal treatment processes, transportation, and storage. Depending on moisture in a coal and the technology applied, the coal may need to be dried before use. For instance, coals entering dry-feed gasifiers typically need to be dried to achieve appropriate gasification temperature and reduce system thermal loss.

5 Coal Types Used in the Previous System Studies

A list of coal types utilized in the energy system studies completed since 2004 is tabulated in Exhibit 5-1. High volatile bituminous coals (such as Illinois No. 6 and Pittsburgh No. 8) have been utilized in multiple studies. Subbituminous coals from the Powder River Basin as well as North Dakota lignite are also relatively well represented. There were no system studies completed since 2004 that considered low volatile bituminous, medium volatile bituminous or "super-compliance" subbituminous coal as a design fuel.

While most of the records include a proximate analysis, an ultimate analysis, and coal heating value, a few also contain ash composition and fusion temperatures, grindability index, and trace element composition.

Exhibit 5-1 Coal types used in past NETL system studies

Name	Seam/Mine	Coal Rank	Notes	Reports	Date
ND Lignite	Freedom-Beulah, ND	Lignite	High Sodium	Repowering with APFBC Series: Leland Olds	Mar-04
				Cost and Performance for Low-Rank Pulverized Coal Oxycombustion Energy Plants	Oct-10
				Cost and Performance Baseline for Fossil Energy Plants; Volume 2: Coal to Synthetic Natural Gas and Ammonia	Oct-10
				Cost and Performance Baseline for Fossil Energy Plants; Volume 3b: Low Rank Coal to Electricity : Combustion Cases	Mar-11
				Cost and Performance Baseline for Fossil Energy Plants; Volume 3a: Low Rank Coal to Electricity : IGCC Cases	Apr-11
TX Lignite	Wilcox Lignite	Lignite	Low Sodium	Polygeneration of SNG, Hydrogen, Power, and Carbon Dioxide from Texas Lignite	Dec-04
			Coal analysis different than first study	Assessment of Alternative FutureGen Plant Designs, Case 7.1.3	Mar-06
PRB	Dry Fork, WY	Subbituminous		Repowering with APFBC Series: Leland Olds	Mar-04
PRB	Wyodak	Subbituminous		Hydrogen Production Process Simulations	Mar-05

Name	Seam/Mine	Coal Rank	Notes	Reports	Date
PRB	Wyodak-Anderson Campbell Co. WY	Subbituminous		KBR transport gasifier study interim report	Feb-05
PRB	Western Energy Area D Rosebud	Subbituminous		Assessment of Power Plants That Meet Proposed Greenhouse Gas Emission Performance Standards Baseline Analysis of a Coal-to-Methanol-to-Gasoline System Alternative Coal Feed Strategies for IGCC Systems	Oct-09 Apr-10 Jul-10
				Cost and Performance for Low-Rank Pulverized Coal Oxycombustion Energy Plants Cost and Performance Baseline for Fossil Energy Plants; Volume 3b: Low Rank Coal to Electricity : Combustion Cases Cost and Performance Baseline for Fossil Energy Plants; Volume 3a: Low Rank Coal to Electricity : IGCC Cases	Oct-10 Mar-11 Apr-11
Beluga Coal	Chuitna/Beluga Mine	Subbituminous		Beluga Coal Gasification Feasibility Study	Jul-06
Healy Coal	Usibelli Mine, Alaska	Subbituminous		Alaska Coal Gasification Feasibility Studies-Healy Coal-to-Liquids Plant	Jul-07

Name	Seam/Mine	Coal Rank	Notes	Reports	Date
Illinois No. 6	Old Ben No. 26 Mine	HV Bituminous	Coal and Trace Mineral Data	Baseline Technical and Economic Assessment of a Commercial Scale Fischer-Tropsch Liquids Facility	Apr-07
				Pulverized Coal Oxycombustion Power Plants	Aug-08
				Evaluation of Alternate Water Gas Shift Configurations for IGCC Systems	Aug-09
				Systems Analysis of an Integrated Gasification Fuel Cell Combined Cycle	Aug-09
				Cost and Performance Baseline for Fossil Energy Plants, Volume 4: Coal-to-Fischer-Tropsch Liquids Using a Dry-Feed Gasifier	Sep-10
				Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2	Nov-10
				CO_2 Capture Ready Coal Power Plants	Apr-08
				Assessment of Hydrogen Production with CO_2 Capture, Vol 1: Baseline State-of-the Art Plants	Aug-10
				Alternative Coal Feed Strategies for IGCC Systems	Jul-10
				Production of High Purity Hydrogen from Domestic Coal: Assessing the Techno-Economic Impact of Emerging Technologies	Aug-10
				Life Cycle Analysis: Existing Pulverized Coal Power Plant	Sep-10
				Life Cycle Analysis: Integrated Gasification Combined Cycle (IGCC) Power Plant	Sep-10
				Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant	Dec-10
				Advancing Oxycombustion Technology for Bituminous Coal Power Plants: An R&D Guide	Feb-10
				Preliminary Results of the Modified Benfield Process for CO_2 Capture from Syngas	Mar-10
				Ionic Liquids-Based Absorption Process for Warm CO_2 Capture from Syngas	Oct-10

Name	Seam/Mine	Coal Rank	Notes	Reports	Date
Illinois No. 6 (cont.)			Illinois No. 6 coal composition is different than QGESS	Current and Future IGCC Technologies, Vol 1	Oct-08
				Eliminating the Derate of Carbon Capture Retrofits	Oct-10
				Greenhouse Gas Reductions in the Power Industry Using Domestic Coal and Biomass, Vol. 2: PC Plants	Jan-11
				Dry Catalytic Reforming of Fischer-Tropsch Tail Gas, Rev. 1	Feb-11
				Current and Future Technologies for Gasification-Based Power Generation, Vol 2	Nov-10
				Comparison of Pratt and Whitney Rocketdyne IGCC and Commercial IGCC Performance	Jun-06
				Oxy-Fired Pressurized Fluidized Bed Combustion Assessment	Sep-10
				Industrial Size Gasification for Syngas, Substitute Natural Gas and Power Production	Apr-07
Pittsburgh No. 8		HV Bituminous		Hydrogen Production Process Simulations	Mar-05
				Power Plant Water Usage and Loss Study	May-07
				Technical and Economic Assessment of Small-Scale Fischer-Tropsch Liquids Facilities	Feb-07
				Assessment Of Alternative FutureGen Plant Designs - Draft Topical Report	Apr-05
NYPA Bailey Clean Coal		HV A Bituminous		NYPA IGCC Project Site Specific Design	Dec-04
Southeast Ohio Coal		HV Bituminous	Coal and Ash Data	Task 3 Gasification Plant Cost and Performance Optimization	May-05

6 Typical Market Quality of Selected Coals

According to the Keystone Coal Industry Manual [11], mine operators generally hold recent coal quality data confidential. Publicly available coal-quality data are 20 or more years old, and 72 percent of these data are from areas that are now mined out. Several public sources of typical market coal quality are utilized in this report. However, those sources do not yield consistent mine and/or seam specific data.

The Form 423[1] Database [12] contains coal quality information by coal rank and by source. However, the Supplier field in the Form 423 database does not provide uniform data. It may contain the sales company name, the mining company name, the mine name, a seam indication, or varying abbreviations of these depending on who completed the form. Furthermore, coal in Form 423 is identified by rank, but not by the seam where the coal was mined, i.e., bituminous coals from all regions (Appalachian, Interior, etc.) are grouped into the same category. Not all data fields are complete for all records.

Average coal quality of commercially shipped coal in The Utah Geological Survey [13] is reported by state and by county, but not by the coal rank and mine.

Thus, the average quality of commercially shipped coal from EIA Form 423 and the Utah Geological Survey, presented in Exhibit 6-1 and Exhibit 6-2, can be used for indicative comparison only.

[1] The Form No. 423 is a compilation of data for cost and quality of fuels delivered to electric power plants to be used for determination of electric rates. Prior to 2002, the "Monthly Cost and Quality of Fuels for Electric Plants Database" came from FERC Form 423, and included cost information as well as Btu, sulfur, and ash content, but the specific supplier was not included in the FERC database. Currently the "Monthly Cost and Quality of Fuels for Electric Plants Database" comes from EIA Form 423 and includes supplier information as well as Btu, sulfur, and ash content, but the cost information is not included in the database. Both databases are available from the EIA website.

Exhibit 6-1 Form 423 summary of 2001-2003 coal quality by coal type

	Weighted Average, As Received		
	HHV, Btu/lb	Sulfur, %	Ash, %
Illinois No.6	11,176	2.95	8.29
PRB	8,652	0.34[1, 2]	5.03
Texas Lignite	6,482	1.27	17.07

Notes:

1. *About 49 percent of PRB supplied coal in 2003 had sulfur content not exceeding 0.3 percent (AR, by wt); About 28 percent of PRB supplied coal in 2003 had sulfur content between 0.3 percent and 0.4 percent (AR, by wt); About 16 percent of PRB supplied coal in 2003 (all from the same source) had sulfur content above 0.5 percent (AR, by wt)*
2. *The PRB coal supply contracts appear to comprise two distinct groups. One group (approximately 33 percent of total tonnage) is so called "super compliance coal," with the sulfur content around 0.2 percent; the second group (approximately 16 percent of total tonnage) is coal with relatively high sulfur content of 0.5 percent.*

Exhibit 6-2 Average quality of commercially shipped coal by state per Utah Geological Survey

State	HHV Btu/lb, (dry)	Ash (% dry)	Sulfur (% dry)	Mercury (ppm dry)	Chlorine (ppm dry)
Illinois[1]	12,992	9.9	2.6	0.083	1,691
Pennsylvania[1]	13,089	13.2	1.9	0.258	1,048
Kentucky[1]	13,153	11.2	1.9	0.104	1,054
West Virginia[1]	13,264	12.0	1.4	0.119	1,044
Wyoming[2]	12,033	8.1	0.6	0.053	131
Montana[2]	11,633	10.0	0.8	0.070	107
North Dakota[3]	10,603	14.4	1.3	0.097	159
Texas[3]	9,332	25.5	1.6	0.125	370

Notes:

1. *Coals from Illinois, Pennsylvania, Kentucky and West Virginia are predominantly high volatile bituminous*
2. *Coals from Wyoming and Montana are mostly from the Powder River Basin and subbituminous in rank*
3. *Coals from North Dakota and Texas are mostly lignite*

7 Recommended Coal Analysis

The coal analyses recommended for the QGESS are presented in the following sections. The data sources, if known, are documented at the beginning of each coal rank section. Some coal types have been used in previous system analysis studies and the compositions presented here are consistent with prior modeling efforts. However, in some instances the original data source for those compositions is no longer known and therefore simply specified as "previous system studies."

It should be noted that low volatile and medium volatile bituminous coals are mostly utilized by the steel industry. Combustion of these coals in wall-fired boilers may present a significant challenge due to their low reactivity. Regardless, recommended compositions are still provided for those coal types. Two options for high volatile bituminous coals, Pittsburgh No. 8 and Illinois No. 6, are included. There are also two options for lignite (Texas and North Dakota) and subbituminous coal ("super-compliance" and high [relatively] sulfur).

7.1 Low Volatile Bituminous

The low volatile bituminous coal analysis in Exhibit 7-1 is based on the Argonne Premium Coal Sample Database entry for coal from the Pocahontas No.3 seam. [1] The same source was used for the ash mineral matter analysis and the ash fusion temperatures.

Exhibit 7-1 Low volatile bituminous coal

Coal Name	N/A
Coal seam nomenclature	Pocahontas No.3
Mine	Buchanan Co. WV
ASTM D388 Rank	Low Volatile Bituminous

Proximate Analysis[2,4]	**As-Received**	**Dry**
Moisture	0.65%	0.00%
Volatile Matter	19.14%	19.27%
Ash	4.74%	4.77%
Fixed Carbon	75.47%	75.96%
Total	100.00%	100.00%

Ultimate Analysis[2,4]	**As-Received**	**Dry**
Carbon	86.15%	86.71%
Hydrogen	4.20%	4.23%
Nitrogen	1.26%	1.27%
Sulfur	0.66%	0.66%
Chlorine	0.19%	0.19%
Ash	4.74%	4.77%
Moisture	0.65%	0.00%
Oxygen	2.15%	2.17%
Total	100.00%	100.00%

Heating Value, Dulong calc.[1,4]	**As-Received**	**Dry**
HHV (Btu/lb)	14,926	15,024
LHV (Btu/lb)	14,539	14,635
HHV (kJ/kg)	34,718	34,946
LHV (kJ/kg)	33,818	34,040

Coal Name	N/A
Coal seam nomenclature	Pocahontas No.3

Hardgrove Grindability Index[3]	100 HGI

Typical Ash Mineral Analysis[2]		
Silica	SiO_2	32.0%
Aluminum Oxide	Al_2O_3	20.1%
Titanium Dioxide	TiO_2	1.9%
Iron Oxide	Fe_2O_3	15.8%
Calcium Oxide	CaO	12.8%
Magnesium Oxide	MgO	2.0%
Sodium Oxide	Na_2O	2.0%
Potassium Oxide	K_2O	0.6%
Phosphorus Pentoxide	P_2O_5	0.4%
Sulfur Trioxide	SO_3	12.4%
Undetermined		0.0%
Total		100.00%

Typical Ash Fusion Temperatures (°F)[2]		
Reducing		
Initial - Limited deformation		2,183
Softening	H=W	2,240
Hemispherical	H=1/2W	2,310
Fluid		2,407
Oxidizing		
Initial - Limited deformation		2,400
Softening	H=W	2,414
Hemispherical	H=1/2W	2,422
Fluid		2,487

Average trace element composition, dry basis, ppm		**Arithmetic Mean**	**Standard Deviation**
Arsenic	As		
Barium	Ba		
Boron	B		
Beryllium	Be		
Cadmium	Cd		
Cerium	Ce		
Cobalt	Co		
Chromium	Cr		
Copper	Cu		
Gallium	Ga		
Germanium	Ge		
Lanthanum	La		
Lead	Pb		
Lithium	Li		
Manganese	Mn		
Mercury[5,6]	Hg	0.079	0.009
Molybdenum	Mo		
Neodymium	Nd		

Coal Name		N/A	
Coal seam nomenclature		Pocahontas No.3	
Average trace element composition, dry basis, ppm (continued)		**Arithmetic Mean**	**Standard Deviation**
Nickel	Ni		
Niobium	Nb		
Phosphorus	P		
Thorium	Th		
Tin	Sn		
Selenium	Se		
Scandium	Sc		
Silver	Ag		
Strontium	Sr		
Uranium	U		
Vanadium	V		
Ytterbium	Yb		
Yttrium	Y		
Zirconium	Zr		
Zinc	Zn		

Notes:

1. *Calculated Dulong as-received HHV is 14,998 Btu/lb, dry basis is 15,096 Btu/lb*
2. *Proximate analysis, ultimate analysis, mineral matter analysis and ash fusion temperatures are per the Argonne Premium Coal Sample Database [1]*
3. *Ash analysis and Hardgrove Grindability Index are based on typical values per reference [9]*
4. *This coal type has not been used in previous energy system studies*
5. *The mercury concentration was determined from 105 records of the EPA Information Collection Request (ICR) database*
6. *In previous system studies, coal mercury values were the mean plus one standard deviation*

7.2 Medium Volatile Bituminous

The medium volatile bituminous coal analysis in Exhibit 7-2 is based on the Argonne Premium Coal Sample Database for the Upper Freeport coal seam. This analysis is consistent with the average quality of commercially shipped coal from Indiana County, Pennsylvania. [13]

Exhibit 7-2 Medium volatile bituminous coal

Coal Name	N/A
Coal seam nomenclature	Upper Freeport
Mine	Indiana Co, PA
ASTM D388 Rank	Mid Volatile Bituminous

Proximate Analysis[2,4]	**As-Received**	**Dry**
Moisture	1.13%	0.00%
Volatile Matter	29.43%	29.77%
Ash	13.03%	13.18%
Fixed Carbon	56.41%	57.05%
Total	100.00%	100.00%

Ultimate Analysis[2,4]	**As-Received**	**Dry**
Carbon	73.39%	74.23%
Hydrogen	4.03%	4.07%
Nitrogen	1.33%	1.35%
Sulfur	2.29%	2.32%
Chlorine	0.00%	0.00%
Ash	13.03%	13.18%
Moisture	1.13%	0.00%
Oxygen	4.80%	4.85%
Total	100.00%	100.00%

Heating Value, Dulong calc.[1,4]	**As-Received**	**Dry**
HHV (Btu/lb)	13,315	13,467
LHV (Btu/lb)	12,944	13,092
HHV (kJ/kg)	30,971	31,324
LHV (kJ/kg)	30,108	30,451

Hardgrove Grindability Index[3]	95 HGI

Typical Ash Mineral Analysis[2]		
Silica	SiO_2	44.8%
Aluminum Oxide	Al_2O_3	24.1%
Titanium Dioxide	TiO_2	1.3%
Iron Oxide	Fe_2O_3	17.3%
Calcium Oxide	CaO	4.2%
Magnesium Oxide	MgO	1.6%
Sodium Oxide	Na_2O	0.0%
Potassium Oxide	K_2O	2.7%
Phosphorus Pentoxide	P_2O_5	0.1%
Sulfur Trioxide	SO_3	3.9%
Undetermined		0.0%
Total		100.00%

Coal Name		N/A
Coal seam nomenclature		Upper Freeport

Typical Ash Fusion Temperatures (°F)[2, 7]		
Reducing		
Initial - Limited deformation		2,191
Softening	H=W	2,250
Hemispherical	H=1/2W	2,321
Fluid		2,433
Oxidizing		
Initial - Limited deformation		2,140
Softening	H=W	2,170
Hemispherical	H=1/2W	2,200
Fluid		2,225

Average trace element composition, dry basis, ppm

		Arithmetic Mean	Standard Deviation
Antimony	Sb		
Arsenic	As		
Barium	Ba		
Boron	B		
Beryllium	Be		
Cadmium	Cd		
Cerium	Ce		
Cobalt	Co		
Chromium	Cr		
Copper	Cu		
Fluorine	F		
Gallium	Ga		
Germanium	Ge		
Lanthanum	La		
Lead	Pb		
Lithium	Li		
Manganese	Mn		
Mercury[5,6]	Hg	0.238	0.099
Molybdenum	Mo		
Neodymium	Nd		
Nickel	Ni		
Niobium	Nb		
Phosphorus	P		
Thorium	Th		
Tin	Sn		
Selenium	Se		
Scandium	Sc		
Silver	Ag		
Strontium	Sr		
Uranium	U		
Vanadium	V		
Ytterbium	Yb		
Yttrium	Y		
Zirconium	Zr		
Zinc	Zn		

Notes:

1. *Calculated Dulong as-received HHV is 12,897 Btu/lb, dry basis is 13,044 Btu/lb*

2. *Proximate analysis, ultimate analysis, ash mineral matter analysis, and ash fusion temperatures are per Argonne Premium Coal Sample Database*
3. *Hardgrove Grindability Index is per reference [9]*
4. *This coal type has not been used in previous energy system studies*
5. *The mercury concentration was determined from 396 records of EPA Information Collection Request (ICR) database*
6. *In previous system studies, coal mercury values were the mean plus one standard deviation*
7. *Oxidizing ash fusion temperatures are generally higher than reducing, but these data are as reported by the Argonne Premium Coal Sample Database*

7.3 High Volatile Bituminous

Pittsburgh No. 8 coal has been used in several past system studies as documented in Exhibit 5-1. However, the properties were fairly similar to Illinois No. 6 coal. To represent high volatile bituminous coals with a relatively large deviation in heating value, a new Pittsburgh No. 8 coal analysis, extracted from the U.S. Geological Survey Database [14], is presented. The coal analysis is shown in Exhibit 7-3.

Exhibit 7-3 High volatile bituminous coal analysis (Pittsburgh No. 8)

Coal name	Pittsburgh No. 8
Coal seam nomenclature	N/A
Mine	N/A
ASTM D388 Rank	High Volatile A Bituminous

Proximate Analysis[2,3]	**As-Received**	**Dry**
Moisture[4]	2.63%	0.00%
Volatile Matter	35.82%	36.79%
Ash	9.17%	9.42%
Fixed Carbon	52.38%	53.79%
Total	100.00%	100.00%

Ultimate Analysis[2,3]	**As-Received**	**Dry**
Carbon	73.15%	75.13%
Hydrogen	4.97%	5.10%
Nitrogen	1.46%	1.50%
Sulfur	2.36%	2.42%
Chlorine	0.04%	0.04%
Ash	9.17%	9.42%
Moisture	2.63%	0.00%
Oxygen	6.22%	6.39%
Total	100.00%	100.00%

Reported Heating Value[1,2,3]	**As-Received**	**Dry**
HHV (Btu/lb)	13,116	13,470
LHV (Btu/lb)	12,658	13,000
HHV (kJ/kg)	30,508	31,331
LHV (kJ/kg)	29,443	30,238

Hardgrove Grindability Index[2]	73 HGI

Coal name	Pittsburgh No. 8	
Typical Ash Mineral Analysis[2]		
Silica	SiO_2	41.80%
Aluminum Oxide	Al_2O_3	22.30%
Titanium Dioxide	TiO_2	1.03%
Iron Oxide	Fe_2O_3	22.76%
Calcium Oxide	CaO	3.20%
Magnesium Oxide	MgO	0.70%
Sodium Oxide	Na_2O	0.48%
Potassium Oxide	K_2O	1.51%
Phosphorus Pentoxide	P_2O_5	0.37%
Sulfur Trioxide	SO_3	2.87%
Undetermined		2.94%
Total		100.0%

Typical Ash Fusion Temperatures (°F)			
Reducing			
Initial – Limited deformation		ºF	2,260
Softening	H=W	ºF	2,350
Hemispherical	H=1/2W	ºF	
Fluid		ºF	2,430
Oxidizing			
Initial – Limited deformation		ºF	
Softening	H=W	ºF	
Hemispherical	H=1/2W	ºF	
Fluid		ºF	

Average trace element composition of selected coal samples, dry basis, ppm[2]

		Arithmetic Mean	**Standard Deviation**
Arsenic	As	996	749
Boron	B	42	15
Beryllium	Be	1.2	0.7
Cadmium	Cd	0.08	0.06
Chlorine	Cl	457	367
Cobalt	Co	4.0	2.6
Chromium	Cr	14.0	6.0
Copper	Cu	7.1	3.5
Fluorine	F	75.0	105
Mercury[5]	Hg	0.23	0.20
Lithium	Li	12.9	7.9
Manganese	Mn	19.8	13.3
Molybdenum	Mo	2.7	2.6
Nickel	Ni	11.1	6.5
Phosphorus	P	181	221
Lead	Pb	4.3	2.6
Tin	Sn	0.6	0.5
Selenium	Se	1.4	0.8
Thorium	Th	1.8	0.7
Uranium	U	0.9	1.0
Vanadium	V	16.0	8.0
Zinc	Zn	12.6	8.5

Notes:

1. *Calculated Dulong HHV, As-Received – 13,335 Btu/lb, Dry – 13,695 Btu/lb*

2. *Proximate analysis, ultimate analysis, HHV, ash mineral analysis, Hardgrove Grindability Index, ash fusion temperature and trace element composition were average values based on 46 Pittsburgh formation coal samples extracted from the USGS database* [14]
3. *This analysis is different than Pittsburgh No. 8 coal analyses that were used in past system studies*
4. *In previous system studies, this coal was dried to 2.5 percent moisture for dry-feed gasifiers*
5. *In previous system studies, mercury values for coal analyses were the mean plus one standard deviation*

The coal analysis from the Old Ben Mine No. 26 has been utilized in several major studies, including multiple revisions of Volume 1 of the Cost and Performance Baseline Report. [15] The coal quality in this guideline is consistent with the commercial offerings for the high volatile bituminous rank coal and coals shipped from the state of Illinois. The composition documented in this guideline has been reported previously in other studies dating back to 1996. [16] The high volatile bituminous coal analysis (Illinois No. 6) is presented in Exhibit 7-4.

Exhibit 7-4 High volatile bituminous coal analysis (Illinois No. 6)

Coal name	Illinois No. 6
Coal seam nomenclature	Herrin (No. 6)
Mine	N/A
ASTM D388 Rank	High Volatile A Bituminous

Proximate Analysis[6]	**As-Received**	**Dry**
Moisture[7]	11.12%	0.00%
Volatile Matter	34.99%	39.37%
Ash	9.70%	10.91%
Fixed Carbon	44.19%	49.72%
Total	100.00%	100.00%

Ultimate Analysis[6]	**As-Received**	**Dry**
Carbon	63.75%	71.72%
Hydrogen	4.50%	5.06%
Nitrogen	1.25%	1.41%
Sulfur	2.51%	2.82%
Chlorine	0.29%	0.33%
Ash	9.70%	10.91%
Moisture[7]	11.12%	0.00%
Oxygen	6.88%	7.75%
Total	100.00%	100.00%

Reported Heating Value[1,6]	**As-Received**	**Dry**
HHV (Btu/lb)	11,666	13,126
LHV (Btu/lb)	11,252	12,712
HHV (kJ/kg)	27,113	30,506
LHV (kJ/kg)	26,151	29,444

Hardgrove Grindability Index	60 HGI

Coal name	Illinois No. 6	
Typical Ash Mineral Analysis[2]		
Silica	SiO_2	45.0%
Aluminum Oxide	Al_2O_3	18.0%
Titanium Dioxide	TiO_2	1.0%
Iron Oxide	Fe_2O_3	20.0%
Calcium Oxide	CaO	7.0%
Magnesium Oxide	MgO	1.0%
Sodium Oxide	Na_2O	0.6%
Potassium Oxide	K_2O	1.9%
Phosphorus Pentoxide	P_2O_5	0.2%
Sulfur Trioxide	SO_3	3.5%
Undetermined		1.8%
Total		100.0%

Typical Ash Fusion Temperatures (°F)[3]		
Reducing		
Initial – Limited deformation		2,194 ºF
Softening	H=W	2,260 ºF
Hemispherical	H=1/2W	2,345 ºF
Fluid		2,415 ºF
Oxidizing		
Initial – Limited deformation		2,250 ºF
Softening	H=W	2,300 ºF
Hemispherical	H=1/2W	2,430 ºF
Fluid		2,450 ºF

Average trace element composition of coal shipped by Illinois mines, dry basis, ppm[4]

		Arithmetic Mean	**Standard Deviation**
Arsenic	As	7.5	8.1
Boron	B	90	45
Beryllium	Be	1.2	0.7
Cadmium	Cd	0.5	0.9
Chlorine	Cl	1671	1189
Cobalt	Co	3.5	1.3
Chromium	Cr	14	6
Copper	Cu	9.2	2.5
Fluorine	F	93	36
Mercury[5]	Hg	0.09	0.06
Lithium	Li	9.4	7.1
Manganese	Mn	38	32
Molybdenum	Mo	8.4	5.7
Nickel	Ni	14	5
Phosphorus	P	87	83
Lead	Pb	24	21
Tin	Sn	0.9	0.7
Selenium	Se	1.9	0.9
Thorium	Th	1.5	0.4
Uranium	U	2.2	1.9
Vanadium	V	31	16
Zinc	Zn	84.4	84.2

Notes:

1. *Calculated Dulong HHV, As-Received - 11,634 Btu/lb, Dry - 13,089 Btu/lb*
2. *Typical ash mineral analysis is based on Combustion Technologies Composition Source Book, May, 2005*
3. *Reducing condition ash fusion temperature data are from source [16], and oxidizing condition typical ash fusion temperature data are based on the Combustion Technologies Composition Source Book, May, 2005*
4. *Average trace element composition of coal shipped by Illinois mines is based on 34 samples, 2004 Keystone Coal Industry Manual [11]*
5. *A mercury value of 0.15 ppm was used for Illinois No. 6 in previous system studies, which is the mean plus one standard deviation*
6. *The system studies using this coal type are documented in Exhibit 5-1*
7. *In previous system studies this coal was dried to 5 percent or 6 percent moisture for dry-feed gasifiers*

7.4 "Super-Compliance" Subbituminous PRB Coal

"Super-compliance" subbituminous coal analysis is based on a coal sample reported by the Sheldon Station power plant for an energy system study conducted in 2003 [17], and is presented in Exhibit 7-5.

Exhibit 7-5 "Super-compliance" subbituminous coal analysis

Coal name	PRB
Coal seam nomenclature	Wyodak/Anderson
Mine	Rochelle Coal Co.
ASTM D388 Rank	Subbituminous C

Proximate Analysis[5]	**As-Received**	**Dry**
Moisture	27.42%	0.00%
Volatile Matter	31.65%	43.61%
Ash	4.50%	6.20%
Fixed Carbon	36.43%	50.19%
Total	100.00%	100.00%

Ultimate Analysis[5]	**As-Received**	**Dry**
Carbon	50.23%	69.21%
Hydrogen	3.41%	4.70%
Nitrogen	0.65%	0.89%
Sulfur	0.22%	0.30%
Chlorine	0.02%	0.03%
Ash	4.50%	6.20%
Moisture	27.42%	0.00%
Oxygen	13.55%	18.67%
Total	100.00%	100.00%

Heating Value[2,5]	**As-Received (Reported)**	**Dry (Dulong calc.)**
HHV (Btu/lb)	8,800	11,546
LHV (Btu/lb)	8,486	11,113
HHV (kJ/kg)	20,469	26,856
LHV (kJ/kg)	19,738	25,850

Hardgrove Grindability Index	52 HGI

Coal name		PRB
Coal seam nomenclature		Wyodak/Anderson

Ash Mineral Analysis		
Silica	SiO_2	33.40%
Aluminum Oxide	Al_2O_3	16.30%
Titanium Dioxide	TiO_2	1.20%
Iron Oxide	Fe_2O_3	5.20%
Calcium Oxide	CaO	21.50%
Magnesium Oxide	MgO	6.40%
Sodium Oxide	Na_2O	1.90%
Potassium Oxide	K_2O	0.35%
Phosphorus Pentoxide	P_2O_5	1.20%
Sulfur Trioxide	SO_3	11.70%
Barium Oxide	Ba_2O	0.56%
Strontium Oxide	SrO	0.27%
Manganese Dioxide	MnO2	0.02%
Total		100.00%

Ash Fusion Temperatures (°F)		
Reducing		
Initial - Limited deformation		2,170 ºF
Softening	H=W	2,190 ºF
Hemispherical	H=1/2W	2,200 ºF
Fluid		2,230 ºF
Oxidizing		
Initial - Limited deformation		2,200 ºF
Softening	H=W	2,220 ºF
Hemispherical	H=1/2W	2,250 ºF
Fluid		2,290 ºF

Trace element composition, dry basis, ppm[1,3]

		Reported	**WY Average**
Antimony	Sb	0.62	<0.4
Arsenic	As	1.5	<3
Barium	Ba	N/A	300
Boron	B	43	70
Beryllium	Be	0.4	N/A
Cadmium	Cd	0.56	<0.15
Cerium	Ce	N/A	<20
Cobalt	Co	N/A	2
Chromium	Cr	6	7
Copper	Cu	12	8
Fluorine	F	76	N/A
Gallium	Ga	N/A	3
Germanium	Ge	N/A	<2
Lanthanum	La	N/A	<7
Lead	Pb	5	<3
Lithium	Li	N/A	4.6
Manganese	Mn	9	N/A
Mercury[4]	Hg	0.1	0.1
Molybdenum	Mo	N/A	1
Neodymium	Nd	N/A	<15
Nickel	Ni	5	5
Niobium	Nb	N/A	1.5

Coal name		PRB	
Coal seam nomenclature		Wyodak/Anderson	
Phosphorus	P	N/A	N/A
Thorium	Th	N/A	2.7
Tin	Sn	N/A	N/A
Selenium	Se	0.3	<0.8
Scandium	Sc	N/A	1.5
Silver	Ag	0.24	N/A
Strontium	Sr	N/A	100
Uranium	U	N/A	<0.9
Vanadium	V	17	15
Ytterbium	Yb	N/A	0.5
Yttrium	Y	N/A	5
Zirconium	Zr	N/A	15
Zinc	Zn	8	17.9

Notes:

1. *N/A = not available*
2. *Calculated Dulong HHV As-Received - 8,380 Btu/lb*
3. *Average trace element composition found in Wyoming coals is based on 48 published analyses in the 2004 Keystone Coal Industry Manual [11]*
4. *Mercury values for other coal analyses used in previous system studies were the mean plus one standard deviation*
5. *The system studies using this coal type are documented in Exhibit 5-1*

7.5 Subbituminous

The subbituminous coal analysis in Exhibit 7-6 represents a relatively smaller group of PRB coals with sulfur content higher than 0.5 percent. The original source of the composition data is not known, but it is very close to the composition reported for Wyoming coal in the Argonne Premium Coal Sample Database. [1]

Exhibit 7-6 Subbituminous coal from PRB field

Coal seam nomenclature	Montana Rosebud
Coal field	PRB, Area D
Mine	Western Energy Co.
ASTM D388 Rank	Subbituminous

Proximate Analysis[2]	**As-Received**	**Dry**
Moisture[3]	25.77%	0.00%
Volatile Matter	30.34%	40.87%
Ash	8.19%	11.04%
Fixed Carbon	35.70%	48.09%
Total	100.00%	100.00%

Ultimate Analysis[2]	**As-Received**	**Dry**
Carbon	50.07%	67.45%
Hydrogen	3.38%	4.56%
Nitrogen	0.71%	0.96%
Sulfur	0.73%	0.98%
Chlorine	0.01%	0.01%
Ash	8.19%	11.03%
Moisture[3]	25.77%	0.00%
Oxygen	11.14%	15.01%
Total	100.00%	100.00%

Heating Value[1,2]	**As-Received**	**Dry (Dulong calc.)**
HHV (Btu/lb)	8,564	11,516
LHV (Btu/lb)	8,252	11,096
HHV (kJ/kg)	19,920	26,787
LHV (kJ/kg)	19,195	25,810

Hardgrove Grindability Index	57

Coal seam nomenclature	Montana Rosebud
Coal field	PRB, Area D

Ash Mineral Analysis		
Silica	SiO_2	38.09%
Aluminum Oxide	Al_2O_3	16.73%
Titanium Dioxide	TiO_2	0.72%
Iron Oxide	Fe_2O_3	6.46%
Calcium Oxide	CaO	16.56%
Magnesium Oxide	MgO	4.25%
Sodium Oxide	Na_2O	0.54%
Potassium Oxide	K_2O	0.38%
Phosphorus Pentoxide	P_2O_5	0.35%
Sulfur Trioxide	SO_3	15.08%
Barium Oxide	Ba_2O	0.00%
Strontium Oxide	SrO	0.00%
Unknown	MnO2	0.84%
Total		100.00%

Ash Fusion Temperatures (°F)		
Reducing		
Initial - Limited deformation		2,238 ºF
Softening	H=W	2,254 ºF
Hemispherical	H=1/2W	2,270 ºF
Fluid		2,298 ºF
Oxidizing		
Initial - Limited deformation		2,284 ºF
Softening	H=W	2,301 ºF
Hemispherical	H=1/2W	2,320 ºF
Fluid		2,367 ºF

Trace element composition, dry basis, ppm

		Reported	**WY Average**
Antimony	Sb		
Arsenic	As		
Barium	Ba		
Boron	B		
Beryllium	Be		
Cadmium	Cd		
Cerium	Ce		
Cobalt	Co		
Chromium	Cr		
Copper	Cu		
Fluorine	F		
Gallium	Ga		
Germanium	Ge		
Lanthanum	La		
Lead	Pb		
Lithium	Li		
Manganese	Mn		
Mercury[4]	Hg	0.056	0.025
Molybdenum	Mo		
Neodymium	Nd		
Nickel	Ni		
Niobium	Nb		

Coal seam nomenclature		Montana Rosebud	
Coal field		PRB, Area D	
Phosphorus	P		
Trace element composition, dry basis, ppm (continued)			
		Reported	**WY Average**
Thorium	Th		
Tin	Sn		
Selenium	Se		
Scandium	Sc		
Silver	Ag		
Strontium	Sr		
Uranium	U		
Vanadium	V		
Ytterbium	Yb		
Yttrium	Y		
Zirconium	Zr		
Zinc	Zn		

Notes:

1. *Calculated Dulong HHV As-Received - 8,548 Btu/lb*
2. *The system studies using this coal type are documented in Exhibit 5-1*
3. *In previous system studies, this coal was dried to 5 percent moisture for dry-feed gasifiers*
4. *In previous system studies, mercury values used for coals were the mean plus one standard deviation*

7.6 North Dakota Lignite

The North Dakota lignite analysis is based on a coal sample reported by the Leland Olds plant for a 2004 system analysis study [18], and is presented in Exhibit 7-7.

Exhibit 7-7 North Dakota lignite analysis (high-sodium)

Coal name	High Sodium Lignite
Coal seam nomenclature	Beulah-Zap
Mine	Freedom, ND
ASTM D388 Rank	Lignite A

Proximate Analysis[5]	**As-Received**	**Dry**
Moisture	36.08%	0.00%
Volatile Matter	26.52%	41.48%
Ash	9.86%	15.43%
Fixed Carbon	27.54%	43.09%
Total	100.00%	100.00%

Ultimate Analysis[5]	**As-Received**	**Dry**
Carbon	39.55%	61.88%
Hydrogen	2.74%	4.29%
Nitrogen	0.63%	0.98%
Sulfur	0.63%	0.98%
Chlorine	0.00%	0.00%
Ash	9.86%	15.43%
Moisture	36.08%	0.00%
Oxygen	10.51%	16.44%
Total	100.00%	100.00%

Heating Value[2,5]	**As-Received**	**Dry (Dulong calc.)**
HHV (Btu/lb)	6,617	10,427
LHV (Btu/lb)	6,364	10,032
HHV (kJ/kg)	15,391	24,254
LHV (kJ/kg)	14,804	23,335

Hardgrove Grindability Index	Not applicable

Coal name		High Sodium Lignite
Ash Mineral Analysis		
Silica	SiO_2	35.06%
Aluminum Oxide	Al_2O_3	12.29%
Titanium Dioxide	TiO_2	0.58%
Iron Oxide	Fe_2O_3	5.12%
Calcium Oxide	CaO	14.39%
Magnesium Oxide	MgO	6.61%
Sodium Oxide	Na_2O	5.18%
Potassium Oxide	K_2O	0.64%
Phosphorus Pentoxide	P_2O_5	0.00%
Sulfur Trioxide	SO_3	16.27%
Barium Oxide	Ba_2O	0.56%
Strontium Oxide	SrO	0.27%
Manganese Dioxide	MnO2	0.02%
Unknown		3.00%
Total		100.00%

Ash Fusion Temperatures (°F)[6]		
Reducing		
Initial - Limited deformation		2,045 ºF
Softening	H=W	2,085 ºF
Hemispherical	H=1/2W	2,125 ºF
Fluid		2,165 ºF
Oxidizing		
Initial - Limited deformation		2,125 ºF
Softening	H=W	2,155 ºF
Hemispherical	H=1/2W	2,190 ºF
Fluid		2,215 ºF

Trace element composition, dry basis, ppm[3]		**As Reported**[1]
Antimony	Sb	N/A
Arsenic	As	67
Barium	Ba	7000
Boron	B	1590
Beryllium	Be	N/A
Cadmium	Cd	0.89
Cerium	Ce	N/A
Cobalt	Co	N/A
Chromium	Cr	29
Copper	Cu	50
Fluorine	F	N/A
Gallium	Ga	N/A
Germanium	Ge	N/A
Lanthanum	La	N/A
Lead	Pb	38.7
Lithium	Li	N/A
Manganese	Mn	N/A
Mercury[4]	Hg	0.116
Molybdenum	Mo	N/A
Neodymium	Nd	N/A
Nickel	Ni	27
Niobium	Nb	N/A

Coal name		High Sodium Lignite
Phosphorus	P	N/A
Trace element composition, dry basis, ppm (continued)		
		As Reported
Thorium	Th	N/A
Tin	Sn	N/A
Selenium	Se	11
Scandium	Sc	N/A
Silver	Ag	N/A
Strontium	Sr	N/A
Uranium	U	N/A
Vanadium	V	77.2
Ytterbium	Yb	N/A
Yttrium	Y	N/A
Zirconium	Zr	N/A
Zinc	Zn	73.8

Notes:

1. *N/A = not available*
2. *Calculated Dulong HHV As-Received – 6,665 Btu/lb*
3. *Trace element composition is as reported in the sample*
4. *Mercury value is the mean (0.081 ppm) plus one standard deviation (0.035 ppm) of selected samples from the EPA Information Collection Request database*
5. *The system studies using this coal type are documented in Exhibit 5-1*
6. *Ash fusion temperatures are the midpoint of a range*

7.7 Texas Lignite

Texas lignite was used in several energy system studies since 2004. [19, 20] The coal composition used in the two studies was not consistent. The coal analysis presented in the QGESS does not exactly match either study composition, but is based on mean values of the Texas Wilcox Group lignite coals from the 2004 Keystone Coal Industry Manual. [11] The Keystone Coal reference provided values closest to the weighted average Texas lignite values for the coals sold on the U.S. market (Exhibit 6-1), and are also very close to the FutureGen study composition. [19] Ash of Wilcox Group lignite contains less than 1 percent sodium. Thus, both low-sodium and high-sodium lignite (ND lignite) are represented in the QGESS. The Texas lignite analysis is presented in Exhibit 7-8.

Exhibit 7-8 Texas lignite analysis (low-sodium)

Coal seam nomenclature	Wilcox Group
Coal name	Mean Values
Mine	TX
ASTM D388 Rank	Lignite

Proximate Analysis [1,3]	**As-Received**	**Dry**
Moisture	32.00%	0.00%
Volatile Matter	28.00%	41.18%
Ash	15.00%	22.06%
Fixed Carbon	25.00%	36.76%
Total	100.00%	100.00%

Ultimate Analysis [1,3]	**As-Received**	**Dry**
Carbon	37.70%	55.44%
Hydrogen	3.00%	4.41%
Nitrogen	0.70%	1.03%
Sulfur	0.90%	1.32%
Chlorine	0.02%	0.03%
Ash	15.00%	22.06%
Moisture	32.00%	0.00%
Oxygen	10.68%	15.71%
Total	100.00%	100.00%

Heating Value, Dulong calc. [3]	**As-Received**	**Dry**
HHV (Btu/lb)	6,554	9,638
LHV (Btu/lb)	6,277	9,231
HHV (kJ/kg)	15,243	22,417
LHV (kJ/kg)	14,601	21,472

Hardgrove Grindability Index	60 HGI

Coal seam nomenclature		Wilcox Group
Typical Ash Mineral Analysis		
Silica	SiO_2	44.10%
Aluminum Oxide	Al_2O_3	15.03%
Titanium Dioxide	TiO_2	1.03%
Iron Oxide	Fe_2O_3	8.96%
Calcium Oxide	CaO	11.91%
Magnesium Oxide	MgO	2.67%
Sodium Oxide	Na_2O	0.70%
Potassium Oxide	K_2O	0.78%
Phosphorus Pentoxide	P_2O_5	0.00%
Sulfur Trioxide	SO_3	11.77%
Undetermined		3.05%
Total		100.00%

Typical Ash Fusion Temperatures (°F)[2]		
Reducing		
Initial - Limited deformation		2,152
Softening	H=W	2,260
Hemispherical	H=1/2W	2,248
Fluid		2,362
Oxidizing		
Initial - Limited deformation		
Softening	H=W	
Hemispherical	H=1/2W	
Fluid		

Average trace element composition, dry basis, ppm		**Arithmetic Mean**	**Standard Deviation**
Antimony	Sb		
Arsenic	As		
Barium	Ba		
Boron	B		
Beryllium	Be		
Cadmium	Cd		
Cerium	Ce		
Cobalt	Co		
Chromium	Cr		
Copper	Cu		
Fluorine	F		
Gallium	Ga		
Germanium	Ge		
Lanthanum	La		
Lead	Pb		
Lithium	Li		
Manganese	Mn		
Mercury[4]	Hg	0.148	0.058
Molybdenum	Mo		
Neodymium	Nd		
Nickel	Ni		
Niobium	Nb		
Phosphorus	P		
Thorium	Th		

Coal seam nomenclature		Wilcox Group	
Tin	Sn		
Average trace element composition, dry basis, ppm (continued)			
		Arithmetic Mean	**Standard Deviation**
Selenium	Se		
Scandium	Sc		
Silver	Ag		
Strontium	Sr		
Uranium	U		
Vanadium	V		
Ytterbium	Yb		
Yttrium	Y		
Zirconium	Zr		
Zinc	Zn		

Notes:

1. *Coal analysis is based on mean values for Texas Wilcox Group Coals, 2004 Keystone Coal Industry Manual [11]*
2. *Ash fusion temperatures (reducing) are for Northeast of Wilcox Group*
3. *The system studies using this coal type (but not this composition) are documented in Exhibit 5-1*
4. *In previous systems studies, mercury values used for other coals were the mean plus one standard deviation*
5. *In previous systems studies, this coal was dried to 15 percent, 12 percent or 8 percent moisture for dry-feed gasifiers*

8 Revision Control

Exhibit 8-1 Revision table

Revision Number	Revision Date	Description of Change	Comments
1	February 5, 2014	Document formatted	

9 References

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